Progress in Monitoring Strategies for Risk Reduction in Geologic CO₂ storage

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Abstract

Commercial, demonstration and pilot geologic CO₂ storage (GCS) projects have provided a wealth of practical experience in monitoring technologies. In this manuscript we review a few key projects, specific geophysical methods, well-based methods, geophysical workflows and some suggested best practices. These practices are often driven and governed by regulatory requirements (e.g. U.S. Environmental Protection Agency [US-EPA] Class VI underground injection regulation) and the need for effective reservoir management of pressures and volumes as well as the site-specific risks to containment, plume migration, and underground sources of drinking water. Reducing uncertainty in monitoring is likely to lead to reducing uncertainty in risk. One of our conclusions is the need for field experiment testing that is risk-driven. It is notable that GCS pilot projects have been designed for safe storage, and to date they have been successful. Technical challenges at all geologic CO₂ storage sites include assuring injectivity and capacity predictions are reliable, the fate and subsurface topology of the CO₂ plume is acceptable, regulatory permitting and compliance are accomplished in a timely manner, needed business assurances are supported by quantitative technical data, and the storage operation is acceptable to stakeholders. There is risk associated with all of these challenges necessitating a monitoring program utilizing both direct and indirect monitoring methods. Geophysical monitoring is viewed as a key component in approaching risk assessment because of the direct association of risk and monitoring in GCS. In this review we provide a framework for monitoring and then present some specific monitoring tools that may be useful for regulatory compliance, as well as technologies that are applicable to leakage detection. Since the Department of Energy National Risk Assessment Program (DOE NRAP) is focused on quantitative risk assessment, we focus on quantitative geophysical monitoring. Important concepts for a successful integration of monitoring and risk assessment include the following: characterization of key parameters of risk and methods to monitor those parameters, the feedback between risk and monitoring, and the development of risk-based strategies to assess and update monitoring plans and tools. We briefly review current work in assessing uncertainty in

important monitoring technologies, such as seismic and electrical geophysical surveys, and acknowledge that there is both temporal and spatial uncertainty in monitoring, in addition to the measurement uncertainty of specific tools. In our opinion monitoring approaches for subsurface imaging, such as 3D-reflection seismic, 3D-Vertical Seismic Profiling (VSP), cross well seismic, electromagnetic and electrical technologies, and well-log based measurements produce proxies for saturation and mass that, when properly calibrated and interpreted, are robust quantitative estimates of these key storage parameters. Understanding the uncertainty in these proxies is important in risk-driven monitoring. The cost of high-potential geophysical monitoring technologies impacts application of these methods to quantitative risk assessments. We therefore examine the concept of value of information (VOI) that is expected to play a role in selection of monitoring tools. We also conclude that monitoring of leakage scenarios has had minimal field validation and thus quantifying and reducing risk will require dedicated experiments that probe and test uncertainty in fault/fracture-zone and wellbore leakage.

Keywords

Geologic CO₂ Storage, Carbon Dioxide, Geophysical Monitoring, Uncertainty, Risk Assessment, Area of Review, Post Injection Site Care, Value of Information, and Regulatory Compliance.

Introduction

Technical challenges at geologic CO₂ storage (GCS) sites include assuring that injectivity and capacity predictions are reliable, fate and configuration of the CO₂ plume is acceptable, regulatory permitting and compliance is accomplished in a timely manner, needed business assurances are supported by technical data, and that the storage operation is acceptable to stakeholders (Friedmann and Hovorka, 2004; DOE, 2012; Annetts et al., 2012; CSFL, 2013; Dixon and Romanak, 2015; Jones et al., 2015). There is risk, defined as the product of hazard probability and hazard impact, associated with all of these challenges (DOE, 2013a).

Geologic storage monitoring using geophysical methods provides the basic data that are used to meet these challenges (DOE, 2012; Stickland et al., 2014). The types of risk that are addressed in this paper are related to insufficient injectivity, insufficient storage capacity and loss or lack of containment, and in particular, failure to protect underground sources of drinking water. The link between risk assessment and monitoring is intuitively made in the monitoring strategy for any sequestration project, since monitoring is inevitably focused on storage components perceived to have higher risk. Wellbore integrity, subsurface seal integrity, reservoir characteristics and subsurface plume topology, fault characteristics and geometries, ground water impacts, and induced seismicity are all typical targets of quantitative geophysical monitoring (DOE, 2011; Wright, 2011).

The integration of monitoring and risk assessment is of interest to stakeholders, including researchers, state and federal regulators, financial assurance providers, and storage project operators (DOE, 2012). The United States Environmental Protection Agency (US EPA) (EPA, 2016) and other regulators require that carbon capture and storage (CCS) projects implement monitoring, reporting, and verification (MRV) systems that detect leakage of CO₂ from either the containment reservoir or away from the storage site. As an example of this integration, the US EPA requires Class VI wells, which represent an important underground injection control program (UIC) element for groundwater protection under the Safe Drinking Water Act (SDWA), to include a monitoring and testing (M&T) plan during the operational phase of the project. Also, complementary to, and building upon the EPA UIC program for carbon dioxide geological sequestration wells is the subpart RR source category associated with the Clean Air Act (CAA), which requires a US EPA-approved MRV plan and report of the amount of CO₂ sequestered using a mass balance approach (EPA 2015, 2016).

In this paper, we focus on geophysical monitoring of CO₂ storage in saline reservoirs and on risks of subsurface geologic storage (DOE, 2013a, 2013b, 2014). We do not review issues such as geochemistry-based monitoring methods, well bore integrity or leakage, atmospheric release (Jones et al., 2009) or CO₂ storage ‘credits’. This overview, conducted as part of the U.S. Department of Energy’s (DOE) National Risk Assessment Partnership (NRAP), reviews NRAP and DOE work that addresses key questions related to monitoring strategies, and addresses an approach to integrating monitoring strategies with quantitative risk assessment and risk reduction. A quantitative risk assessment approach allows different monitoring strategies to be compared based on impact to the overall project risk assessment. In future storage projects using this approach, we expect monitoring strategies to be assessed based on a modeling evaluation of a suite of flow/leakage models used in a quantitative risk assessment. Therefore the monitoring response can directly inform, and hopefully reduce, the assessed risk via mitigation of detected problems.

Risk Driven Strategic Monitoring

A continuous chain of responsibility is expected to surround CO₂ injection and storage activity, as illustrated in Figure 1. Stewardship includes initial site screening, final site selection, initial risk assessment, developing injection engineering specifics, managing CO₂ injection, plume configuration, evolving risk, site closure and decommissioning (Wright 2011; Wright et al., 2009; EU 2009).

Key decisions in monitoring a large storage project have a variable but significant financial project impact. Examples of these key decisions include:

- What monitoring technologies are optimal for the entire area-of-review (AOR) and can these technologies better define and possibly reduce the size of the monitored AOR?
- What technologies should be used for post-injection site care (PISC) and can monitoring help define and/or reduce the overall project PISC time-line?
- What monitoring technologies should be used for reservoir management to ensure conformance during active CO₂ injection?
- What technologies are optimal for early and definitive leakage detection?
- If leakage is detected or suspected, what monitoring is needed to confirm, guide and assess mitigation efforts?

A site-specific cost/benefit approach to selecting post-injection monitoring techniques should be developed in association with a quantitative risk assessment. A quantitative risk assessment allows monitoring techniques to be compared directly based upon their ability to detect the more significant risks, such as seal leakage, at a GCS site. This detection ability is then a ‘benefit’ that can be graded between low and high project benefit rankings. Costs can also be associated with each monitoring technique for a GCS site. With these two rankings, benefit and cost, a large number of monitoring techniques can then be compared by with respect to their respective estimated benefits and costs for the GCS site by plotting them on a Boston Square (or Boston Chart) (Hannis, 2013). Figure 2 shows the results of such an analysis by Mathieson, et al. (2010) where high-benefit, low-cost monitoring options are in a low cost / high benefit conceptual quadrant labeled “*just do it*”; these techniques were then used in monitoring. At this GCS site the high cost / low benefits methods were avoided, low cost / high benefit routinely included, and methods in the high cost / high benefit, were given careful consideration. In this specific cost/benefit case repeat 3D reflection seismic was located in the high cost / high benefit quadrant and was included in the GCS site monitoring program. Because CO₂ reservoirs can be complexly heterogeneous, a high-resolution approach that includes reservoir characterization and modeling is preferred (Mathieson et al., 2010). In addition to understanding the monitoring techniques that reside in the “*just do it*” quadrant for a site, two important additional concerns are the time line for post-injection site care and determining the impact of volume and rate of CO₂ injection on the monitoring design.

Injection volume, mass, and subsurface reservoir dimensions vary between different projects of different scale (pilot, demonstration, commercial) and are highly relevant to the choice of monitoring design and technologies. A sense of the variation of planned injection volumes of 20 sites is shown in Table 1. These sites include onshore and offshore saline aquifers, enhanced oil recovery (EOR) (Harbert and Lipinski, 2010), and injection into depleted gas reservoirs (Jenkins et al., 2012). The issues raised in the design of accurate and efficient monitoring programs for

injection capacities that vary between 1 kilo tonne (kt) and 129 million tonnes (Mt) are central to scaling current and future monitoring efforts. For example, in the Figure 2 review, the monitoring technique involving time lapse (4D) seismic, a higher cost / high benefit monitoring technique, was used to improve reservoir characterization and understand injection related changes within the reservoir. Table 2, modified after Arts and Vandeweyer, (2011), shows some of the broader challenges to monitoring subsurface CO₂ using geophysical methods that should be considered with the goal of reducing risks through the monitoring activity.

In addition to the mass of the injection, injection rate is important for predicting area of reservoir pressure build-up. Birkholzer et al. (2009) modeled the area of pressure build up for large volume injection into deep saline aquifers, extending their models to a 70-year post injection period for various confining zone characteristics. Depending in large part upon seal permeability, reservoir pressure build-up at distances exceeding 100 km is predicted as shown in Figure 3 (Birkholzer et al., 2009). Such regions are consistent with Ringrose et al., (2011) who present mass and rate of CO₂ injection for the Sleipner, Snøhvit, and In Salah sites. Updated data show that 15.5 Mt of CO₂ have been injected at Sleipner (to June 2015); 3.8 Mt at In Salah (operation halted), and 3.0 Mt of CO₂ injected at Snøhvit (to December 2015). Large reservoir dimensions could be challenging for monitoring onshore sites, and may provide an important criterion for storage site selection.

Risk-driven strategic monitoring design will evaluate technologies for detection of key variables associated with risk, and will develop monitoring strategies and protocols using the output from tools quantifying risks and uncertainties, such as the NRAP integrated assessment models (IAM) and reduced order models (ROM) (Carroll et al., 2014; Dai et al., 2014; Zhang and Pau, 2012, Pawar et al., 2015). Strategic monitoring research provides insight into the most effective approaches to evaluate technologies, based on consideration of geologic site variability (DOE, 2013a; Pevzner et al., 2012; Peters, 2007).

Outputs from risk quantification and evolution of risk profiles are used to identify key drivers for risk and to assess, commonly via numerical modeling, monitoring approaches to reducing magnitudes and uncertainties of risks and potential liabilities. Incorporation of higher certainty subsurface information with the CGS operation could decrease both hazard probability and hazard impact at a CGS site. For example, a suite of models of site-response to CO₂ injection may indicate that fault leakage is a risk-controlling factor, and in this case a suite of forward modeling tools could be used to assess detectability of fault leakage (DOE, 2012; Vu-Hoang et al., 2008, Will, 2012). These forward models should be calibrated using locally relevant core samples, stress analysis, subsurface geophysical imaging volumes and other site-specific datasets, such as modern geophysical well logs.

Key parameters to monitor (and to be modeled) are expected to include effective fluid pressures within the reservoir and in the above-zone monitoring interval (AZMI); the presence of injected or reservoir fluids within the overburden, groundwater chemistry; and induced seismicity. Note that each of these CGS site parameters being monitored is best understood given a well-constrained knowledge of the pre-injection background behavior of each of these phenomena.

In addition, evaluation using monitoring modeling can provide confidence in identifying the most critical signals to monitor, as well as the frequency and duration needed for monitoring. A quantitative cost-benefit, or value-of-information analysis, can then identify the most effective monitoring tools and protocols to minimize risks (DOE, 2012).

Value of Information (VOI) for Monitoring

Monitoring strategies are selected on a site-specific basis, often using expert judgment. Quantitative risk assessment needs more rigorous tools. One approach investigated within NRAP is value of information (VOI). Quantitative decision analysis and value of information can aid in (1) linking subsurface uncertainties regarding CO₂ sequestration to economic outcomes and (2) determining when additional information may be useful before making further decisions (e.g. stop injection or conduct additional monitoring).

To demonstrate how VOI can be used for post-injection site care (PISC), Trainor-Guitton et al. (2013), as part of an NRAP study, performed uncertainty quantification (UQ) evaluation of CO₂ and accompanying brine leakage into a shallow aquifer via an abandoned wellbore from a deep reservoir. First, they transformed the range of total dissolved solids (TDS) plume results into a range of possible economic outcomes from an agricultural decision, where groundwater is used to irrigate corn crops, and high saline concentrations result in economic losses. The concept of perfect information and the risk quantification results indicated that any information will only be relevant when considering plumes which exceed 2000 ppm TDS.

Using electrical or electromagnetic methods, with calibrated models for pH and TDS variation, remote sensing geophysical data (e.g. helicopter collected data) can yield accurate estimates of subsurface pH (Lipinski et al., 2008). Trainor-Guitton et al. (2013) showed that a geophysics-based methodology allowed calculation of the reliability of electrical resistance data to detect lower pH/higher TDS brine plumes, using the electrical resistivity response simulated for multiple leakage simulations from an uncertainty quantification (UQ) study. A sensitivity index allowed assessment of the specific geophysical method's sensitivity to plume versus non-plume simulations, where the sensitivity index is a mean log ratio of the electrical response at two different times. In other words, this ratio is the electrical response at a time after CO₂ injection scaled by the electrical response at time=0 (before CO₂ injection). Figure 4 demonstrates the data reliability and resulting posterior. For the sensitivity index range of 0.001-0.002, there is ambiguity in whether or not a plume exists. This analysis allowed estimation of a financial impact directly from electrical resistance monitoring information, which could relate to crop impact. Above a sensitivity index value of 0.002 there is no ambiguity, all of the models at or above this sensitivity index value included a leaky wellbore. The value of the crop resources can then be compared to the cost of monitoring and appropriate decisions made (Trainor-Guitton et al. 2013). This is one specific example of quantifying a monitoring tool's value in risk reduction to compare to the cost of the tool.

Regulatory Compliance

Regulatory compliance is a first order goal for strategic monitoring and so we describe some major regulatory drivers. Beginning in 2011, the US EPA Underground Injection Control (UIC) program established the Class VI CO₂ injection well category for the purposes of protecting underground sources of drinking water (USDW), and set minimum technical criteria for site injection permits to include geologic site characterization, area of review (AOR), corrective action, financial responsibility, well construction, operation, mechanical integrity testing (MIT), monitoring, well plugging, post-injection site care (PISC), and site closure. Figure 5, reproduced from the UIC Program Class VI Well Testing and Monitoring Guidance (TMG) (EPA, 2013), shows a schematic monitoring program with potential project risk. For AOR and PISC, two

topics of importance are monitoring ground water quality above the confining zone, and plume and pressure front tracking. AOR and PISC are defined as follows:

Area of review (AOR): The region surrounding the geologic carbon storage/sequestration project where USDWs may be endangered by CO₂ the injection activity. The AOR is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected and displaced fluids, and is based on site characterization, monitoring, and operational data.

Post-injection site care (PISC): Appropriate monitoring and other actions (including corrective action) needed following cessation of CO₂ injection to ensure that USDWs are not endangered.

Another example of regulatory guidance for site stewardship provided by the European Commission, Directive 2009/31/EC, includes four guidance documents (EU, 2009) detailing the following CCS activities relevant to the post-injection time line:

- CO₂ storage life-cycle risk management framework.
- Characterization and storage infrastructure, CO₂ stream composition, monitoring and corrective measures.
- Criteria for ultimate transfer of responsibility to the competent authority.
- Financial security and financial mechanisms.

Within the European Commission framework, the post-injection, or closure/decommissioning activities for large storage sites include the development of a monitoring plan with targets and methods, post-closure monitoring, updated site characterization and risk assessment and inspections by the Competent Authority (CA) following the site closure. Before transfer of the site to the CA, long term containment of CO₂ must be verified, the site sealed, and monitoring and assessment demonstrated for 20 years.

Monitoring Technologies

Monitoring technologies can be divided into direct and indirect measurement based methods. Direct measurement tools include pressure or temperature, measured at a specific *in-situ* location in the subsurface. Indirect measurements observe a proxy, such as seismic velocity or electrical resistivity, which is physically related to the subsurface property of interest. These observations are then analyzed and interpreted to estimate the subsurface material property. For example, electrical or seismic monitoring are indirect monitoring methods; the actual observations (elastic or electrical characteristics of the subsurface) are analyzed and interpreted to derive the parameters of interest, for example subsurface fluid saturation. Another example is the earlier VOI discussion in which calibrated electrical resistivity could be analyzed to accurately estimate subsurface water characteristics such as TDS and pH (Trainor-Guitton et al. 2013). Geophysical methods in general are indirect methods of monitoring.

For both AOR and PISC, seismic imaging methods are considered beneficial tools. In each of the sites associated with Table 1 seismic imaging was a significant input to the site characterization and monitoring. Typically the first use of seismic is for constructing a detailed structural and stratigraphic model and establishing baseline seismic responses. This initial 3D reflection seismic survey can also serve as a structural framework for the spatial location of other monitoring data, and as a baseline for determining temporal (time-lapse 4D) (Kragh and Christie, 2002) changes in seismic properties (Cantillo, 2011). A key application of 3D/4D reflection

seismic for AOR is the indirect measure of spatial and temporal changes in pore fluids and variations in effective pressure. Effective pressure, defined as the difference between confining and pore pressure, can influence poroelastic characteristics that are resolvable using these seismic methods. Perturbations in pore pressure can have a variety of impacts, such as opening compliant cracks or pores, that may be observed using seismic methods. Such pore-pressure perturbations have been related to induced seismicity (e.g. Mavko et al., 2003; Shapiro, 2015). There is a large body of knowledge related to estimating formation pore fluids and pressure using calibrated seismic data (Landrø et al., 2001, 2003; Sayers, 2010).

A variety of advanced seismic techniques can be used to calculate seismic attributes from 3D reflection seismic volumes (Simm and Bacon, 2014) and to invert post stack seismic data to determine material properties, such as Lamè parameters (Goodway et al., 1997). In addition, pre-stack amplitude variation with offset (AVO) analysis (Castagna and Swan, 1997; Castagna et al., 1998; Castagna and Backus, 2007) use relationships that contain both rock framework and fluid terms, allowing these aspects of the injection reservoir to be investigated in detail and to efficiently utilize properties of the near-field and far-field reflection seismic data prior to the reflection seismic stacking operation. An example associated with CO₂ injection at a Permian basin site had pre-stack AVO analysis identifying a useful proxy for subsurface CO₂ (Purcell et al., 2009; Purcell et al., 2010; Harbert et al., 2011). In this analysis the pre-stack AVO attribute proxy was defined within the injection reservoir and constrained at the top by a caprock unit. When extracted as a geobody from the dataset and interpreted, this AVO-anomaly feature was observed to have a flat bottomed AVO attribute expression through the reservoir and was interpreted to represent a pore-phase variation, based on comparison with a rock-calibrated petrophysical model, microcomputer tomography (μ CT) analysis, and well logs (Mur et al., 2011).

Borehole seismic methods such as vertical seismic profiles (VSP), 3D-VSP, and continuous active-source seismic monitoring (CASSM) (Daley et al., 2008; Cheng et al., 2010; Daley, et al., 2015) have application for higher spatial resolution, better signal to noise characteristics, easier direct calibration, and more rapid time-lapse monitoring near wellbores (Coueslan 2013). These methods require wellbore access for receiver placement and provide information at generally higher spatial resolution in a more limited subsurface region. For post-injection site care, seismic methods are likely to be used at time intervals that are adapted to the project and site. Because of cost and access requirements, there are limitations to the frequency of seismic data acquisition. A minimum number of such seismic imaging surveys might consist of one baseline followed by a repeat survey, although as the CGS site activity progresses additional surveys might be beneficial. Advances in technology, such as distributed acoustic sensing with fiber optics, have potential to greatly reduce the cost of repeat surveys via low-cost permanent sensing cables (Daley, et al, 2015a).

Numerical models of flow and leakage that are generated for quantitative risk assessment can be used for monitoring design via forward modeling of monitoring tool performance based on the flow models. Cost-effective and reliable reservoir monitoring (such as reflection seismic, VSP, or 3D-VSP) implies an optimal sensor deployment that minimizes survey cost and maximizes information resulting from reservoir property changes. The forward model is important because it may show that failure or a failure precursor might not be detectable, which would immediately impact the monitoring design and perhaps even the feasibility of the site.

Conventional seismic monitoring survey designs are typically based on seismic-wave-field illumination analyses, which cannot determine the best receiver locations for effective and reliable monitoring of reservoir property changes. In contrast, Denli and Huang (2010) introduced an approach for designing optimal seismic monitoring surveys by analyzing sensitivities of elastic waves with respect to reservoir geophysical property changes. This method is based on differentiating the elastic-wave equations with respect to geophysical parameters. Numerical modeling demonstrates that time-lapse seismic survey designs based on elastic-wave sensitivity analysis can be starkly different from designs based on elastic-wave field illumination. For time-lapse seismic monitoring, receivers should be placed at locations where elastic-wave sensitivities are significant; and elastic-wave sensitivity analysis provides a numerical tool for optimizing seismic monitoring designs. In a related example, Shang and Huang (2012) used elastic-wave sensitivity analysis (Denli and Huang, 2010) to model optimal time-lapse survey design for monitoring CO₂ leakage through fault zones for a hypothetical project site. Two stages of CO₂ leakage through fault zones were simulated. In the early stage of leakage, when CO₂ is confined in a relatively deep region, the results of elastic-wave sensitivities show that the most desired location for receivers at the surface is on the hanging-wall side of the fault zone, for normal faults with high dip angles or reverse faults. The surface receiver locations most sensitive to a change of elastic parameters (e.g. P- and S-wave velocity and density) are similar to one another, and are often not sensitive to the seismic source location. In a late stage of leakage, in which CO₂ migrates close to the surface, the modeling results demonstrate that the best region at the surface for time-lapse seismic surveys is very sensitive to the source location and to the elastic parameter to be monitored.

Time-lapse seismic data can be used to quantify changes of geophysical properties in a CO₂ storage reservoir. Inverting time-lapse seismic datasets independently can result in inaccurate estimation of reservoir geophysical property changes caused by CO₂ injection and migration. Joint inversion of time-lapse seismic datasets can significantly improve inversion accuracy (Zhang and Huang, 2013; Yang et al., 2014; Lin and Huang, 2015). A case study of using time-lapse walkaway VSP survey at the SACROC enhanced oil recovery (EOR) field demonstrated that CO₂ injection results in a velocity decrease in the injection zone (Yang, et al, 2014).

Well-based logging tools (e.g. wire-line well logging) provide highly detailed measurements directly within the formations of interest and are critical for AVO, seismic inversion and to calibrate and better understand other geophysical data, such as cross well or reflection seismic. Log-based measurements include conductivity, pressure, temperature, acoustic velocity, nuclear magnetic resonance (NMR), electrical and electromagnetic responses, borehole images, and formation fluid composition (Kirksey, 2012). Processing and analysis of various acoustic, electrical and nuclear measurements lead to estimates of other rock and fluid properties, such as porosity, permeability, salinity, and geomechanical properties (Schlumberger, 1991; Schlumberger 1989). Analysis of pulsed neutron logging allows indirect estimation of CO₂ saturation and is commonly used in CO₂ EOR projects, although results are highly dependent on quality of the cement bond (Nelson and Guillot, 2006). Essentially all well logging tools are localized in their sensitivity to the near-well region, but are commonly extrapolated to populate 3D subsurface site models. Wire-line well logging data from initial characterization wells are used for the early definition of AOR, and in some cases wire-line logging could be included as part of PISC monitoring programs. Incorporating structural data from borehole log data can considerably improve geophysical electrical inversion results (Doetsch et al., 2012, 2013). Above-storage-zone fluid sampling is a direct measurement of storage security and knowledge of

fluid composition is important to calibrate and aid in the interpretation of PISC related electrical and electromagnetic geophysical monitoring. An innovative technology, the U-tube fluid sampler (Freifield et al., 2005), is a tool for direct fluid sampling which can be deployed at multiple depths as a permanent installation to allow a multi-year sampling program.

Microgravimetry- (the temporal change of gravity at the microGal scale [$1 \mu\text{Gal} = 10^{-6} \text{ m/s}^2$]) is a cost-effective and relatively rapid means of observing changes in density distribution in the subsurface, particularly those changes caused by the migration of fluids with differing densities. Time-lapse gravity has been used since 1961 (Allis and Hunt, 1986), but substantial improvements in gravimeter technology, and the advent of highly precise Global Positioning Satellite (GPS) systems, have led to rapid growth in microgravity applications. This technology has been successfully applied to carbon sequestration at Sleipner (Alnes et al., 2008); aquifer recharge studies in Utah and elsewhere (Chapman et al., 2008; Davis et al., 2008) and to hydrocarbon EOR surveillance in Alaska (Ferguson et al., 2007). This method gives direct estimates of densities, and its cost of implementation is low among geophysical methods. Drawbacks are that sensitivity decreases with depth and the solution is non-unique. Microgravimetry is most useful when combined with other methods such as surface deformation and seismic.

Surface deformation measurements have been successfully used for decades to monitor operations at oil and gas fields (Yerkes and Castle, 1969). Interpretation in terms of increases in volume or pressure at depth is also routinely performed (inverse or forward poroelastic modeling). Modern technologies applied to deformation monitoring include GPS based systems, tiltmeters, and Interferometric Synthetic Aperture Radar (InSAR).

High resolution GPS surveys can measure surface displacement and are commonly deployed along profiles centered on injection wells. Permanent GPS stations, or GPS monuments, offer greater accuracies and higher temporal sampling and can be used to very accurately monitor surface displacement. Tiltmeters, instruments built around a highly sensitive electrolytic bubble level that can measure tilt movements as low as one nanoradian (McColpin, 2009) can be deployed in surface or borehole configurations to detect rock deformation. In addition to the amplitude of the deformation, tiltmeter observations produce strain vectors that allow determining more precisely the location of the source of deformation than does GPS alone.

Interferometric Synthetic Aperture Radar (InSAR) is a method to generate surface displacement maps from images acquired by airborne or satellite-borne radar at different times (Yang et al., 2015). By comparing radar returns to a sensor, phase displacements maps are generated by comparing interferograms of phase and amplitude variations. InSAR processing then produces a time series of displacements of the ground surface. Depending on satellite logistics, the interval between two satellite images over the same location can vary between 4 and 21 days. InSAR techniques have been implemented at many CO₂ storage sites, including Weyburn, Canada; Decatur, Illinois; and the Dover 33 Reef in the Michigan Basin. At In Salah, Algeria, a significant surface uplift of 5 mm/year was observed after injection of CO₂ (Morris et al., 2011; Vasco et al., 2010), which was interpreted to represent a subsurface feature of concern. Advanced processing of 3D reflection seismic data identified the subsurface feature accurately in the seismic volume, an example of integrating complementary monitoring technologies (Zhang et al., 2015).

Field Scale Testing of Monitoring Technology

Integrating monitoring with quantitative risk assessment requires understanding the field-scale uncertainties (i.e. the limitations) of each monitoring method. For some storage sites reducing risk may require improvement in monitoring technologies (Dobbs et al., 2009; DOE, 2012). Field tests of monitoring technologies are needed to assess uncertainty and drive improvements. This section briefly reviews some of the US DOE technology tests of monitoring modalities and their implications for improved subsurface imaging, reservoir monitoring and leak detection; as well as results from commercial scale injection at In Salah, Sleipner and Snøhvit, and monitoring plans for the Gorgon and Quest projects.

US DOE and NRAP Monitoring Technology Examples

The Cranfield pilot study was part of the DOE's Regional Carbon Sequestration Partnership (RCSP) program, led by the National Energy Technology Laboratory (NETL) and operated by the Southeast Carbon Sequestration Partnership (SECARB) (Hovorka, 2011). Cranfield is an EOR site in Mississippi, USA, using a natural, not anthropogenic, source of CO₂. The monitoring program at Cranfield is summarized in Hovorka et al. (2013), and was designed to advance research-oriented goals. Thus, the monitoring program was expanded beyond the typical EOR monitoring program, and even beyond what might be considered typical for a CO₂ storage monitoring program, in order to consider research aspects of the monitoring modalities. A non-quantitative risk assessment at Cranfield concluded that well penetrations of the confining layers were the top ranked leakage risk.

The monitoring tools used at Cranfield to investigate leakage detection are well documented for the detailed area study (DAS), which has injection and monitoring wells perforated below the oil-water contact (Hovorka et al., 2006; Hovorka et al., 2013; Ajo-Franklin, et al., 2013). Much of the Cranfield monitoring technology is applicable to saline storage as well as to EOR. Geophysical monitoring was completed over a variety of spatial scales and included detailed petrophysical studies, analysis of wireline well logs, crosswell seismic, 3D and 4D (time-lapse) VSP (Daley, et al, 2015b) and surface seismic surveys.

The Cranfield 3D-VSP study consisted of two different investigations of VSP technology sponsored by the NRAP program and related to improving quantitative monitoring. These investigations focused on improving subsurface spatial resolution via the use of 3D-VSP technology compared to 3D surface seismic technology. The second investigation was related to improving seismic imaging through least-squares, reverse-time migration processing (Tan and Huang, 2014). This processing allows coping with the sparse distribution of VSP seismic sources often found in land VSP designs, and the avoidance of processing artifacts that may mimic low offset faults or other subsurface discontinuities. Such processing artifacts can result in the erroneous interpretation of faults, and thus incorrect assessment of project risk due to greater geologic uncertainty.

The comparison of conventional processing for Cranfield 3D surface seismic and 3D-VSP showed notably different results for the reservoir interval and for an above-zone monitoring interval (AZMI). Comparing the reflectivity in the intermediate depth AZMI, we see that 3D-VSP resulted in clearer imaging of the weaker reflection events (Figure 6). Because of the higher frequency content and better signal to noise characteristics of the 3D-VSP when

compared with the surface 3D seismic, the 3D-VSP technology appeared to be better suited for conducting time lapse monitoring in zones of weak reflectivity (Daley et al., 2013).

Doetsch et al. (2012, 2013) combined the advantages of hydrological and geophysical data in a fully coupled hydrogeophysical inversion, using iTOUGH2 software (Finsterle, 1999a, 1999b, 1999c). Time-lapse seismic and electrical resistivity tomography (ERT) data from the Cranfield site were inverted using cross-gradient joint inversion. This structural joint inversion approach, based on penalizing deviations from zero of the cross-gradients function between models, ensures structural similarity, while not assuming any specific petrophysical relations between model parameters. Figure 7 shows the inversion of seismic and ERT data for simultaneous changes in seismic velocity and resistivity from baseline surveys to 9 months after the start of the CO₂ injection.

In this method, the individual time-lapse data sets are initially inverted: seismic inversion for changes in seismic velocity, and electrical inversion for changes in conductivity – both related to CO₂ gas saturation. Due to the availability of only one time-lapse seismic data set versus multiple electrical data sets, Doetsch et al. (2012, 2013) created a single ERT data set by averaging 20 days of data after the system reached an apparent steady state. The joint inversion results show a more clearly focused CO₂ plume: in particular, the scatter plots indicate a clearer link between change in velocity and ERT-derived gas saturation. The joint inversion estimated the gas saturation that best matched both the seismic data and the electrical data (Kowalsky et al., 2016). The results of the ERT time-lapse inversion were then combined with the hydrological data (e.g. gas sampling and tracer tests) to test different conceptual aquifer models. This study resulted in a successful site-specific demonstration of joint inversion of resistivity and seismic data. Among the outcomes was the ability to estimate width of fluid flow paths that connect the injection and monitoring wells. The propagation of errors and quantification of CO₂ saturation estimated from ERT at the Cranfield site has been presented in detail by Yang et al., (2014).

An important component of CO₂ storage risk assessment focuses on CO₂ leakage into potable groundwater. The risk of CO₂ leakage into groundwater includes mobilization of naturally occurring trace metals in aquifer sediments. As part of the NRAP program to improve monitoring technology, Dafflon et al. (2012), used laboratory and field experiments to explore the sensitivity of time-lapse complex resistivity response, and associated geochemical transformations, to a dissolved CO₂ plume at Plant Daniel, Mississippi. Results show that electrical resistivity and phase responses correlate well with dissolved CO₂ injection processes. Specifically, resistivity initially decreases due to increase of bicarbonate and dissolved species, after which the resistivity rebounds toward initial conditions due to transition of bicarbonate into non-dissociated carbonic acid. This reaction reduces the total concentration of dissociated species and thus the water conductivity. An electrical phase decrease is also observed. The laboratory studies confirm that field observations of electrical resistivity, similar to cross-well electrical resistivity tomography, could detect dissolved CO₂. Both laboratory and field experiments demonstrate the potential of field-based complex-resistivity methods for remotely monitoring changes in subsurface groundwater quality due to CO₂ leakage. Three dimensional crosswell electrical resistivity tomography (ERT) was used in a shallow CO₂ injection experiment at Vrøgum, in western Denmark (Yang et al., 2015). At this site the overall changes in electrical conductivity (EC) agreed partially with water sample EC and ground penetrating radar (GPR) data. Both of these studies are examples of field testing the monitoring of a leakage scenario.

When data sets from multiple technologies are collected for monitoring, we are often faced with very different measures of subsurface properties, requiring balancing of uncertainty. For example, an integrated analysis of hydrological and geophysical monitoring data requires joint or coupled inversions to estimate the “best” fit to the data, and must address spatial sampling variations between data sets and models. Traditional hydrological data provide high resolution measurements for properties immediately surrounding boreholes, and geophysical cross-borehole measurements are sensitive to subsurface properties over larger regions, but can have lower spatial or temporal resolution and can be difficult to interpret quantitatively.

Industrial Scale Monitoring Examples

For industrial scale monitoring, ground deformation can be a cost-effective modality for detecting possible reservoir leakage. At the commercial CCS project at the In Salah, Algeria, Krechba field, ground deformation was monitored with interferometric synthetic aperture radar (InSAR), using data from satellite-borne synthetic aperture radars (SARs) (Vasco, et al, 2010). InSAR measures millimeter-scale ground surface displacements that occur during the interval between two passes of the satellite by differencing the phases of the radar echoes received from the ground at the two times (Burgmann et al., 2000). Mapping the phase differences produces an interferogram, which is then converted to a displacement map. Data stacks from multiple orbits can be processed to develop displacement time series over periods of years (e.g. Ferretti et al. 2001, 2011). The lack of vegetation at In Salah allows radar back-scattering to remain phase-coherent for long periods of time, a primary requirement for successful application of the technique. Conventional InSAR processing measures scalar range changes along the radar line of sight. A technique developed more recently combines interferograms from ascending (south to north) and descending (north to south) orbits to derive quasi-vertical and quasi-east-west displacement components, and has added value to In Salah monitoring (Rucci et al., 2013). Data from four different SAR satellites have been used to monitor deformation associated with injection into three wells between 2004 and 2011; ENVISAT (Europe), RADARSAT (Canada), Cosmo-SkyMed (Italy), and TerraSAR-X (Germany). During the first phase of injection into well KB-502 between June 2005 and August 2006, surface uplift of as much as 1 cm was clearly imaged, while displacements of a few mm were still imaged with a good signal-to-noise ratio during the second injection phase (Vasco, 2008). Since InSAR measurements are relative, they are reduced to an absolute reference provided by a GPS station located outside of the area of deformation. Motivated by the substantial surface displacements imaged by InSAR, a 71-station array of tiltmeters was installed in 2010. Tiltmeters are capable of measuring very small surface deformations, but useful signals were not recorded from the In Salah network.

In the case of InSalah, InSAR data combined with injection pressure data and an understanding of the estimated caprock fracture pressure threshold, allowed researchers to detect a feature that suggested the possibility of an impacted or compromised caprock seal. This information led the operator to stop injection to avoid leakage into other formations and potentially further compromising the reservoir (White et al., 2014). Numerical modeling of both flow and transport and geomechanics is important to the use of deformation monitoring. Surface displacements related to injection are caused by deformation within and surrounding the subsurface reservoir. These include pressure-driven isotropic volumetric deformation, as well as fracture opening or shear displacement on faults. Therefore, inversion or forward modeling of the displacements

using an appropriate material model provides constraint on fluid pressure migration within the reservoir and perhaps also within the caprock and overburden. This in turn can be used to infer the growth of a CO₂ plume and possible leakage out of the storage reservoir as a function of time, although fluid saturation is not imaged directly. The In Salah InSAR images have been used in numerous modeling (e.g. Morris et al., 2011; Rutqvist et al. 2011; Rinaldi et al., 2013) and inversion studies (Vasco et al., 2010; Rucci et al., 2013; Ramirez and Foxall, 2014) to image the fluid volume change and evolution of pressure distribution surrounding the three injection wells. In addition to mapping pressure migration within the reservoir horizon, the distinctive surface uplift pattern in the vicinity of well KB-502 suggested pressure changes in the overlying caprock. Vasco et al. (2008) also used volume change estimates from InSAR inversion to further invert for reservoir permeability. Importantly, quantitative risk assessment would allow feedback from the numerical modeling of monitoring tools to modify the risk calculations.

In contrast to CO₂ injection at In Salah, the offshore Sleipner CO₂ project in the North Sea has had continuous, commercial scale injection since 1996. Over 16 million metric tons of CO₂, stripped from natural gas production at the Statoil Sleipner West Field, have been stored in sandstones of the Utsria Formation at a depth of 800-1100 meters below the sea floor. The 200 m injection zone has permeabilities of greater than one Darcy, and porosities of up to 40%. Original maximum planned injection was 17 million tons; seismic response and volumetric calculations indicate only 0.003% of the available pore space has been filled, with an estimated pore pressure change of less than 0.1 MPa in the Utsria (Verdon et al., 2013). Thus, there is potential for Sleipner to continue injection for many more years.

Monitoring at Sleipner has had three drivers: operational, regulatory, and public interest/safety/perception. While many monitoring tools can address all three, each driver may have different value of information (Eiken et al., 2011; Jenkins et al., 2015). For example, operational direct monitoring places importance on well head and down-hole pressures, flow rate, gas composition sampling, and direct optical monitoring of the seafloor. Indirect monitoring at Sleipner includes a baseline seismic survey in 1994 (about 3km x 5km) and seven repeat 3D surveys (providing time-lapse or 4D seismic response), as well as electromagnetic (EM) surveys, two repeat gravimetric surveys, and two seabed side-scan sonar surveys, and a controlled source EM survey (Hagen 2012). Microseismic monitoring technology, common at many subsurface injection projects, has not been utilized as of 2013 (Ringrose et al., 2013; Verdon et al., 2013). This program is an example of risk based tool selection since measured pressure and injection rates indicate that induced seismicity is not a high risk at Sleipner (Verdon et al., 2013).

The 4D P-wave seismic imaging of subsurface CO₂ at Sleipner has been a true success (Chadwick et al., 2010; Boait, 2012) and effectively informs the operator that CO₂ is retained in the reservoir and defines the AOR. More recent seismic imaging of the CO₂ uses 3D full-anisotropic, full-waveform inversion to better constrain thickness and fluid properties of CO₂ in sands between intra-reservoir mudstone baffles and near the top of the reservoir (Morgan, 2014). Interpretation of integrated data indicate that CO₂ is dissolving in the brine at a rate of about 1.8% of the mass per year; no CO₂ gas is leaking to the sea floor; and CO₂ has not escaped the primary seal (Hagen 2012). Important observations include: successful subsea seismic imaging is enhanced by the high porosities and permeabilities of the storage unit; seismic detectability also depends on the architecture of the storage reservoir and seal; distributed leakage fluxes through thin low permeability strata may be difficult to detect and interpret; and CO₂ saturations are difficult to quantify, even in thick, porous strata (Ringrose et al., 2013).

As with Sleipner, at Snøhvit the combination of pressure data and interpreted 4-D reflection geophysical seismic data represents a successful application of monitoring and adjustment of subsurface injection operations to decrease risk. The Snøhvit field in the Barents Sea is a commercial natural gas field with a high CO₂ content. At this site CO₂ is produced offshore, then piped and stripped at a nearby LNG processing plant, piped back offshore and re-injected into a saline aquifer (Tremosa et al., 2014). The CO₂ storage reservoir, the Tubåen Formation, consists of interbedded sand layers and fine grained siliciclastic layers. The sedimentary units are compartmentalized by east-west trending faults and have been well-characterized by drilling and repeat 3D reflection seismic surveys. Reservoir pressure was an important concern at this site and interpreted to indicate a complex and partitioned reservoir. Anomalous pressure behavior and 4D reflection seismic analysis led to moving an injection location to another part of the formation to avoid damaging the caprock and risking loss of containment (Chiaramonte et al., 2015). Pressure monitoring using the advanced reflection seismic pre-stack workflow proposed by Landrø (2001) successfully combines time-lapse, near and far offset, and partial seismic stacks to estimate changes in formation pressure (Figure 8). This work is associated with detailed petrophysical forward modeling using core material from the site (Grude et al., 2013).

The industrial Gorgon Project is a Western Australia natural gas field that is associated with high CO₂ content and with monitoring related to offshore CO₂ injection and storage (Tenthorey et al., 2011). During production of natural gas, Chevron, which operates the Gorgon Venture, plans to strip approximately 125 million tons of CO₂ from the natural gas and inject it into a deep saline aquifer under Barrow Island. The target injection zone is the upper massive sandstone and lower unit of the Dupuy Formation. The Dupuy storage units are overlain by siltstones and shales that form a continuous regional seal (Flette et al., 2008; Flette et al., 2009). Recent plans for this site include pressure monitoring as part of a pressure management system, to allow injection of 200 million standard cubic feet (.01 metric tons) per day of CO₂ at an average rate of up to 3.65 million tons per year (Trupp et al., 2013). In combination with observation wells, 4D reflection seismic monitoring is planned to monitor the extent of the CO₂ plume (Colombo et al., 2010) within the Dupuy Formation.

Quest is a commercial CCS project associated with tar sands development in Canada. This project is co-funded by the Governments of Canada and the Province of Alberta in cooperation with Shell Canada Energy, and is associated with the Athabasca Oil Sands Project, a joint venture of Shell Canada, Chevron Canada Limited and Marathon Oil Sands L.P. The goal of this project is the capture of more than one million tons of CO₂ per year, transport by pipeline, and permanent CO₂ storage two kilometers underground (Mitrovic and Malone, 2011). The Quest project has released a detailed review of their measurement, monitoring, and verification (MMV) plan (Bourne, 2011). The MMV plan is based on regulatory compliance; includes risk-based monitoring and site-specific technologies; and is planned to be adaptive with continuous evaluation of monitoring systems. Reflection 3D seismic and VSP surveys will monitor the CO₂ plume extent. In field trials associated with the collection of a VSP, a Distributed Acoustic Sensing (DAS) fiber-optic technology was deployed and found record good quality and repeatable seismic data (Cox et al., 2012). A key focus of the Quest monitoring program is protection of underground sources of drinking water (USDW), and a key task is detection of CO₂ in USDW's. This is an example of risk-driven monitoring which drives the development of tools explored in the groundwater monitoring of the ZERT near-surface CO₂ controlled release project (Lewicki et al., 2007; Sprangler et al., 2010; Strazisar et al., 2009; Oldenburg et al., 2012) and SECARB (Dafflon, et al., 2012), described earlier.

Integration of Monitoring, Uncertainty and Risk Assessment

Wolaver et al. (2013) separated CO₂ storage sites into “greensites” – those that have not had previous subsurface development and “brownsites” – those that have had subsurface activities, typically oil and gas production. They argue for coupling of monitoring and risk assessment, since both risks and optimal monitoring approaches are different for the two types of sites. They conclude that although less effort may be needed to organize existing information to document basic suitability for long-term CO₂ storage at a brownsite, it does not follow that characterization of a brownsite is less challenging, or that the site is more likely to be suitable for geologic carbon storage. At the end of site characterization, a risk assessment should be used to assess remaining uncertainty, and to determine if remaining risks can be made acceptable with monitoring and management.

A quantitative risk assessment will likely define key parameters that impact the risk profile. These key parameters are then targets of monitoring (Figure 9). In a simple example consider VSP reflection amplitude from an above-zone monitoring interval (Cheng et al., 2010). If there is an unexpected increase in VSP amplitude in an AZMI, then the risk profile may be affected due to increased probability of leakage into this interval. Characterizing and quantifying the risk impact from monitoring results would then constitute an important feedback between risk assessment and monitoring. To continue the example, the observed amplitude increase may suggest that the operators add extra monitoring locations to assess the subsurface spatial distribution of the amplitude anomaly, perhaps including a 3D-VSP or walkaway-VSP (e.g. Yang et al., 2014) to characterize a larger region. The increased cost in monitoring to extend acquisition of 3D-VSP data could be assessed in the context of the increased risk of leakage, value of information and mitigation costs.

We propose that modeling of monitoring tool performance, using the same subsurface models as the risk assessment, is needed to quantify the risk (especially when considering mitigation impacts). An example work plan for integrating monitoring modeling with quantitative risk assessment is given in Figure 10 showing pre injection planning. The risk assessment based approach addresses monitoring for three zones - storage complex, above zone and near surface), each of which has coupled geophysical, geomechanical and geochemical modeling whose outputs select optimal monitoring and deployment options that are assessed for cost and risk before conducting baseline surveys. The linkages shown between risk assessment, VOI considerations and geophysical monitoring also fit well into attribution technical approaches (Dixon and Romanak, 2015), which seek to improve CO₂ geological storage monitoring protocols.

Summary and Conclusions

Important ideas in this article are characterization of key parameters of risk, feedback between risk and monitoring, and development of strategies to assess and update monitoring activities. It is important to keep in mind that there is both temporal and spatial uncertainty in geophysical monitoring, in addition to the measurement uncertainty of specific tools. Site specific monitoring uncertainties need to be included in risk-based tool assessment. This article is not intended to be an exhaustive list of tools and technologies, but rather a guide to the key technologies used to date. We also outlined an approach to integrating monitoring strategies with risk assessment and risk reduction. This approach utilizes numerical modeling of monitoring tool results, integrated

with numerical models of flow and transport, to assess the impact of tools, and their uncertainty, on risk. Issues of AOR and PISC are highly impacted by monitoring strategies; and subsurface CO₂ utilization (such as EOR) has separate issues from subsurface storage (such as in saline reservoirs). Our assessment of tools for determination of AOR and selection of post injection monitoring include the success and expected utility of 3D-VSP for reservoir monitoring near wells, and electrical resistivity for groundwater monitoring. The concept of value of information is expected to play a role in risk assessment and the selection of monitoring strategies and tools. It is notable that GCS pilots have been designed for low-risk, safe storage, and they have been successful (e.g. Hosa et al., 2011; Finley, 2012; Cook, 2014; DOE 2011). The sites shown in Table 1 provide an important resource for monitoring storage reservoir response, and selection of monitoring technologies. However, with the exception of small scale near-surface tests, such as the ZERT site, field-scale testing reviewed here only involved monitoring of CO₂ that stayed below the designed upper seal. We believe that understanding risk-driven monitoring uncertainty will require dedicated experiments to probe and test monitoring of actual leakage scenarios, such as the Plant Daniel experiment. Such experiments should include fault zone leakage and well bore leakage (DOE, 2013b), with appropriate monitoring (Daley et al., 2011; DOE, 2013a). Monitoring of intermediate depth ‘thief zones’ is an important component; and monitoring studies of gas-phase CO₂ at shallower intermediate depths are notably lacking. Finally, we conclude that monitoring tools, like good monitoring strategies, must be adaptive to evolving technology (Kudryavtsev et al., 2012) and regulatory drivers, and therefore the integration of monitoring and risk assessment will be a continuing process through the life of a storage site.

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Figure captions:

Figure 1: Role of monitoring in the lifecycle of a commercial CO₂ storage site. Using relative scales, it is suggested that uncertainty decreases with time (after Peters 2007). That is, within a framework of minimum monitoring requirements, measurements, including geophysical monitoring, are made to assure decreasing uncertainty of the GCS site and geological carbon storage.

Figure 2: Monitoring technologies presented in a Boston Square format for the Krechba Reservoir at In Salah, Algeria (Mathieson et al., 2010).

Figure 3: Contours of the change in fluid pressure from the initial hydrostatic condition, or pressure buildup (in bar with a cutoff value of 0.1 bar used to define the contours shown), 70 Years after the end of CO₂ injection for different values of seal rock permeability (k_s in m²) (Birkholzer et al., 2009).

Figure 4: The results of a model in which surface electrodes straddling a leaking wellbore. Shown are a) Data reliability and b) Information pre-posterior for $mcl=2000$ mg/L at time = 50 Years (Trainor-Guitton et al., 2013). This concentration was a key value incorporated in a decision tree that would negatively impact the growth of corn using potentially impacted water resources. For the leak diagnostic mean log ratio (MLR) greater than 0.002, the MLR range was produced only by aquifer realizations that included a plume. At or above this value the probability that a plume existed was 100% (Trainor-Guitton et al., 2013).

Figure 5: Testing and monitoring activities during the life cycle of a storage project (from EPA 2013).

Figure 6: Higher resolution VSP Slices (appearing as an inverted cone shape) inserted into a lower resolution 3D seismic volume. The improved VSP imaging of events in low reflectivity overburden indicates potential improvement for monitoring above-zone leakage.

Figure 7: Inversion of cross well seismic and ERT data for simultaneous changes in seismic velocity and resistivity from a baseline to 9 months after injection of CO₂. A) Individual inversions of the seismic and ERT data sets. B) Joint inversion of both datasets using well log constructed cross-gradient structural constraints. The inversion shown in B is considered more accurate and highlights the potential of utilizing multiple monitoring tools combined with well log constructed constraints.

Figure 8: Estimate of formation pressure calculated from time-lapse 3D reflection seismic data. In the inverted reflection seismic data saturation changes were estimated utilizing the near offset and far offset pre-stack seismic data. Petrophysical models then allowed parameters, including pore-pressure, to be estimated. The injection well is shown by the black dot (Grude et al., 2013).

Figure 9: Relation between geophysical monitoring targets and type of risk (modified from Vu-Hoang et al., 2007).

Figure 10. Schematic flow chart of decision making for pre injection planning which incorporates modeling of geophysical monitoring tools with risk assessment (modified from K. Dodds, pers. Comm., 2014).

Tables

Table 1: Location and estimated storage capacities of 20 projects (modified after Hosa, et al, 2011). Details regarding enhanced oil recovery (EOR) projects and screening criteria can be found in Al Adasani and Bai, 2011).

Project name	Location	Project Type	CO ₂ Injection Planned or Accomplished	Start Date	Project website
Rangely	Rangely, Colorado, USA	EOR	26 Mt	1986	http://emfi.mines.edu/emfi2005/ChevronTexaco.pdf
Sleipner	Norwegian North Sea	Offshore saline	16 Mt	1996	http://www.statoil.com/en/OurOperations/ExplorationProd/ncs/sleipner/Pages/default.aspx
Weyburn	Weyburn, Saskatchewan, Canada	EOR	20 Mt	2000	http://www.ptrc.ca/weyburn_overview.php
Nagaoka	Nagaoka, Japan	Onshore saline	10400t	2002	http://www.rite.or.jp/English/lab/geological/overview.html
Frio	Liberty County, Texas, USA	Onshore saline	1600t	2002	http://www.beg.utexas.edu/enviro/qlyty/co2seq/field_experiment.htm
Ketzin	Ketzin, Germany	Onshore saline	60000t	2004	www.co2sink.org
K12-B	North Sea, Netherlands	Offshore gas field (nearly depleted)	8 Mt	2004	http://www.k12-b.nl
In Salah	In Salah, Algeria	Onshore saline	17 Mt	2004	www.insalahco2.com
Total Lacq	Lacq, France	Onshore depleted gas fields	150000t	2006	http://www.total.com/en/challenges/carbon-dioxide-capture-and-geological-storage/lacq-project-940768.html
PCOR Zama	Zama City, Alberta, Canada	EOR	250000t	2006	http://www.undeerc.org/PCOR/default.aspx
WESTCARB Cholla	Holbrook, Arizona, USA	Onshore saline	1800t	2007	http://www.westcarb.org/index.htm , http://www.bki.com/westcarb/AZ_pilot.html
Snøhvit	Barents Sea, Norway	Offshore saline	23 Mt	2007	http://www.statoil.com/en/TechnologyInnovation/ProtectingTheEnvironment/
SECARB Plant Daniel	Escatawpa, Mississippi, USA	Onshore saline	2750t	2008	http://www.secarbon.org/
MGSC Decatur	Decatur, Illinois, USA	Onshore saline	1 Mt	2008	http://sequestration.org/
SECARB Cranfield Phase III	Cranfield, Mississippi, USA	Onshore saline	5 Mt	2008	http://www.secarbon.org/
MRCSP Gaylord	Gaylord, Michigan, USA	Onshore saline	60000t	2008	http://216.109.210.162/MichiganBasin.aspx
MRCSP R.E. Burger	Shadyside, Ohio, USA	Onshore saline	0	2008	http://216.109.210.162/AppalachianBasin.aspx
MRCSP East	Rabbit Hash,	Onshore	1000t	2008	http://216.109.210.162/CincinnatiArch.aspx

Bend	Kentucky, USA	e saline			
WESTCARB Rosetta	Rio Vista, California, USA	Onshore saline	2000t	2009	http://www.westcarb.org/index.htm , http://www.westcarb.org/Shell geo pilot.htm
Gorgon	Gorgon Area, offshore NW Australia	Offshore saline	129 Mt	2016	http://www.chevronaustralia.com/ourbusinesses/gor gon.aspx

Table 2: Challenges of monitoring subsurface CO₂ (modified after Arts and Vandeweyer 2011).

Concern	Key Question(s)	Key Factors
<i>Resolution</i> of individual monitoring methods.	What is the smallest amount of CO ₂ that can be detected by the method?	Resolution generally depends on the instrument specifications, acquisition geometry and local environmental noise characteristics.
<i>Accuracy</i> of the individual monitoring methods.	What is the uncertainty associated with this measurement?	Accuracy can be divided into the accuracy of the measurement device, an accuracy determined by the local environment (i.e., ambient noise, measurement circumstances) and the accuracy of any associated geophysical processing workflow and interpretation.
<i>Parameters measured</i> by the individual monitoring methods (proxies).	How will this model have additional uncertainties to add to the uncertainty of the quantification? How can model parameters be calibrated more accurately for a field site?	What model or petrophysical data are used to relate the measurement of an indirect parameter that can be related to the presence of CO ₂ through a model?
<i>Acquisition pattern</i> deployed in by the methods (spatial sampling).	What sampling density has acceptable uncertainty to the quantification of leakage detection?	To quantify leakage an integration of measurements over an area are required.
Continuity of the measurements in time (<i>temporal sampling</i>) of the monitoring methods.	What time sampling density will add acceptable uncertainty on the integral quantification of a leakage?	Geophysical sampling at various times (time sampling) can add an uncertainty to the quantification of leakage.
<i>Sensitivity of the method:</i> Separation between	With respect to natural background events, what is	Even if CO ₂ could be detected perfectly, this

background noise and relevant signal in the monitoring methods.	the smallest amount of CO ₂ that can be detected by the method?	would still demand a distinction between CO ₂ leaking from the reservoir and natural background CO ₂ .
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Fig. 1

Fig. 2

Fig. 3

Fig. 4

Fig. 5

**Testing and Monitoring Activities During
Phases of a Geologic Sequestration Project**

Fig. 6

-20 msec time shift applied to match surface data

Fig. 7

a)

b)

Fig. 8

Fig. 9

Geophysical Monitoring Targets

Fig. 10

1: Pre Injection